Advanced NanoMaterials and Technologies for Energy Sector
Open Access Journal
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MODELING OF ASPHALTENE PRECIPITATION IN A LIGHT OIL RESERVOIR WITH HIGH PRODUCING GOR: CASE STUDY

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Article History:

Received 21 April 2019

Revised 27 May 2019

Accepted 05 June 2019

Keywords:

Modeling

High GOR

Asphaltene Precipitation

Oil Reservoirs

Reservoir Management

Abstract:

Asphaltene precipitation is an important phenomenon faced during oil production that causes many problems such as plugging the reservoirs, production wells, and transmission pipelines. Therefore, it is necessary to predict the asphaltene precipitated as a function of temperature and pressure. The aim of this study is to investigate the effect of pressure and temperature on the asphaltene precipitation in an Iranian oil reservoir. For this reservoir, the heaviest component is splitted and regrouped with a Commercial PVT Modelling Software. The new heaviest component is divided into precipitating and non-precipitating components. An equation of state (EOS) is tuned by using experimental data including constant composition expansion (CCE), differential liberation (DL) and separator tests. The results of the stability analysis show that there is a high risk of asphaltene precipitation in this reservoir. The maximum amount of asphaltene precipitation occurs around the saturation pressure. It is also observed that asphaltene precipitation is increased by decreasing the temperature along the production wells and transmission pipe-lines.

1. Introduction

Asphaltene precipitation is a serious and complex problem in the oil industry that affects all stages of oil recovery, including production, processing and transportation. This phenomenon has been observed in many reservoirs with high producing gas oil ratio where it significantly reduces the permeability and oil recovery. This encourages number of researches to study the effect of pressure and temperature on asphaltene precipitation [1].

Asphaltene is specified based on the solution properties of petroleum residue in different solvents which soluble in benzene and insoluble in low molecular weight n-alkanes. It is dark brown to black powdered solid, with no certain melting point. It has proved that it's a difficult task to define the exact chemical structure of Asphaltene [2].

Asphaltene deposition more likely happens in undersaturated light oil reservoirs rather than heavy oil reservoirs [3]. As producing gas oil ratio is increased with time, the amount of asphaltene precipitated becomes significant [4].

One of the reasons of high producing GOR is the injection of gas and light hydrocarbons into the reservoir. By increasing this ratio, the maximum amount of soluble asphaltene in oil decreases and the excess asphaltene is separated from the oil as a solid phase. The accumulation of asphaltenes leads to the formation of Tarmats [5]. Thus, it is important to understand how gas affects the distribution of fluids and asphaltene instability conditions [6].

Various tests used to forecast asphaltene stability in reservoir fluid, such as colloidal stability index, colloidal instability index, Stankiewicz plot, qualitative-quantitative analysis, Heithaus parameter, stability cross plot and etc. These tests do not estimate fully the crude oil stability, because asphaltene precipitation is not only related to crude oil composition [7]. A short explanation of these methods are given below:

1.1. Colloidal Instability Index (CII)

Petroleum is a colloidal system formed by SARA (Saturates, Aromatics, Resins and Asphaltenes) fractions. This index is mathematically showed as the ratio of the sum of flocculants (asphaltene and saturates) to peptizers (aromatics and resins). Peptizers help the stability of asphaltene while flocculants cause asphaltene destabilization. CII is shown with the following relationship:

$$CI = \frac{(Asphaltenes\ in\ wt\%) + (Saturates\ in\ wt\%)}{(Aromatics\ in\ wt\%) + (Resin\ in\ wt\%)} \qquad (1)$$

Asomaning and Watikson (2000) reported the range of CII which specify asphaltene stability condition. According to their report, if CII≤0.7, the Asphaltene fraction is stable. When 0.7≤CII≤0.9, asphaltene stability is unknown, while if CII≥0.9 it tends to be unstable [8].

1.2 Colloidal Stability Index (CSI)

Based on this index, SARA fraction and polarity of components is considered in the calculation of index because asphaltene fraction from stable crude oils is less polar compared with that of unstable crude oils. CSI is shown as below:

$$CSI = \frac{(\varepsilon^{asph} \times Asphaltenes\ in\ wt\%) + (\varepsilon^{sat} \times Saturates\ in\ wt\%)}{(\varepsilon^{arom} \times Aromatics\ in\ wt\%) + (\varepsilon^{res} \times Resin\ in\ wt\%)} \qquad (2)$$

where dielecteric constant value (ε) are listed in table 1 for each SARA fractions [9, 10]:

Table 1. Dielecteric constant value (ε) for each SARA fractions [9, 10]

	ε^{asph}	ε^{sat}	ε^{arom}	ε^{res}
Stable oil	5.5	1.921	2.379	4.7
Unstable oil	18.4	1.921	2.379	3.8

For the range of CSI>0.95, the crude oil is unstable and asphaltene precipitation occurs, while for CSI<0.95 the crude oil is stable [11].

1.3 Stability Index

This index is defined as the ratio of asphaltene to resins and it is widely used because both of these fractions are non-volatile, heavy and can be quantified accurately. Asomaning and Watkinson (2000) reported that if stability index is less than 0.35, then the crude oil will be stable [8].

1.4 Stankiewics Plot

In this method, the ratio of saturates to aromatic are plotted against the ratio of asphaltene to resins ratio. This plot is divided into two zones, which shows the tendency of asphaltene precipitation namely stable and unstable zone. Figure 1 shows the stability criterion of Stankiewics [12].

1.5 Stability Cross Plot

Sepulveda et al (2010) reported a number of plots according to SARA fractionation and qualitative-quantitative analysis method. Figure 2 shows the stability cross plot for different relationships based on SARA analysis. The plotted relationships is as follows [13]:

- SCP1: [Ar/A] vs [(R/A)/(S/Ar)]
- SCP2: [R/A] vs [(R/A)/(S/Ar)]
- SCP3: [R/A] vs [S/Ar]
- SCP4: [Ar/(S/A)] vs [(R/A)/(S/Ar)]

These four plots evaluate the crude oil behavior, avoiding ambiguity and and obtain a unique value of asphaltene stability in crude oils [7].

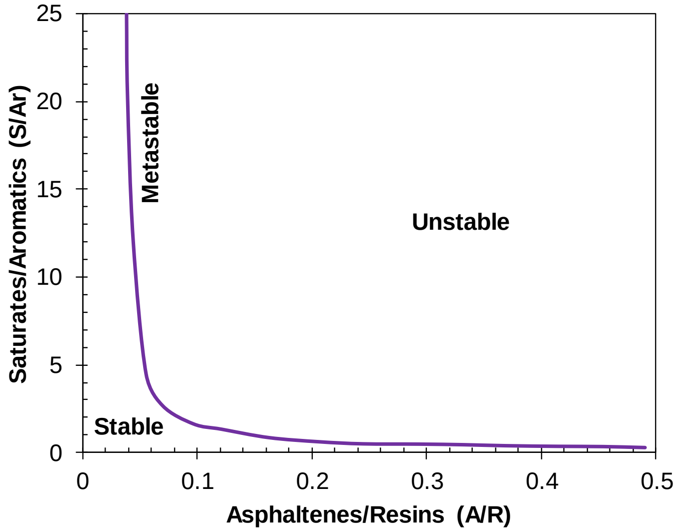


Figure 1. Stability criterion of Stankiewicz [12]

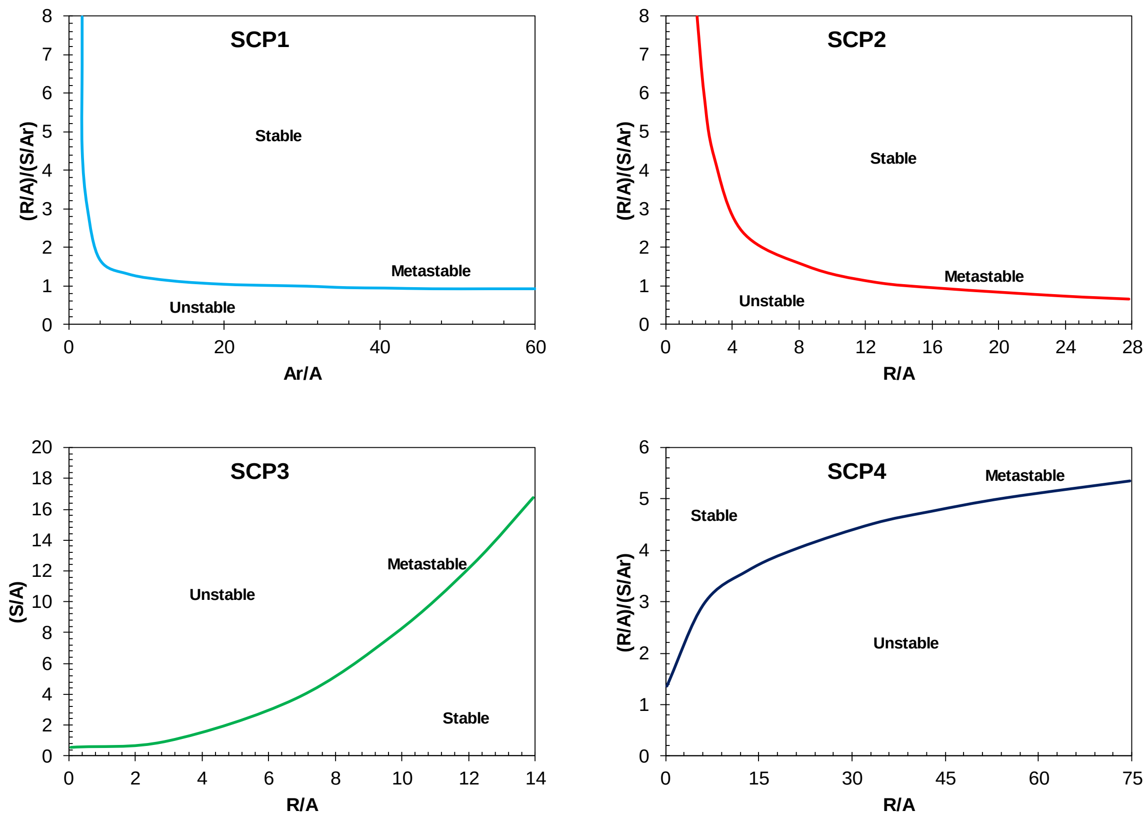


Figure 2. Stability cross plot for different relationships based on SARA analysis [13]

In this paper, all of the above methods has been used to determine the potential of asphaltene precipitation in the studied reservoir. Methods such as CII, CSI, SI and SP which is based on one or two relationships introduced inadequate results. On the other hand, SCP predicted better the asphaltene stability in crude oils. Other methods for determining asphaltene instability contain the experiment work and rigorous calculation [7].

The main goal of this study is determination the potential and the effect of pressure and temperature on the asphaltene precipitation in an Iranian oil reservoir.

2. Materials and Methods

2.1. Crude Oil Properties

The sample of fluid was prepared by surface sampling. After recombination the reservoir fluid composition was determined. Table 2 shows the reservoir fluid composition. A set of experimental tests such as, constant composition expansion, differential liberation and separator tests was available in this study. Table 4 shows the summary results from these test.

2.2 SARA Analysis

SARA test was conducted on the reservoir fluid sample. Table 5 shows the results of SARA analysis.

Table 2. Reservoir oil composition and heavy fraction properties

Components	Reservoir Oil (Mol %)
H_2S	0.27
N_2	0.71
CO_2	1.55
C_1	40.01
C_2	8.12
C_3	5.35
iC_4	1.02
nC_4	2.45
iC_5	1.04
nC_5	1.32
C_6	4.94
C_7	4.67
C_8	2.92
C_9	3.79
C_{10}	2.95
C_{11}	2.75
C_{12}^{+}	16.15
Total	**100.00**

Table 3. Reservoir oil composition after spilitting and regrouping

Components	Reservoir Oil (Mol %)
N_2	0.2699678
CO_2	0.70991534
H_2S	1.5498152
CH_4	40.005229
C_2H_6	8.1190317
C_3H_8	5.349362
IC_4	1.0198784
NC_4	2.4497078
IC_5	1.039876
NC_5	1.3198426
C_6-C_{11}	22.017374
C_{12}-C_{20}	4.4833402
C_{21}-C_{29}	3.2387371
C_{30}-C_{35}	1.6426098
C_{36A+}	6.3776687
C_{36B+}	0.4076444

Table 4. **Summary of tests result**

°F	174
psia	2496
SCF/STB	626.35
g/lit	1.1661
Rbbl/Stb	1.3779
g/cc	0.7336
Rbbl/Stb	1.3623
g/cc	0.7421
°API	29

Molecular weight of residual oil	285
Molecular weight of C_{12}^{+} fraction	548
Molecular weight of Reservoir oil	128
Sp.Gr. of C_{12}^{+} Fraction @ 60 °F	0.9286

Table 5. Results of SARA analysis

Saturates wt.%	**Aromatics** wt.%	**Resins** wt.%	**Asphaltenes** wt.%
66.70	29.80	0.70	2.80

2.3 Procedure

The potential of asphaltene precipitation is investigated with 5 methods such as, colloidal instability index (CII), colloidal stability index (CSI), stability index (SI), Stankiewics plot and stability cross plot (SCP). Then, the model of asphaltene precipitation has been built by using a multi-phase flash calculation in a PVT simulator. The fluid behavior are described by using Peng-Robinson equation of state. Regression has been performed to tune the EOS using the experimental data from the CCE, DL and separator tests.

The precipitation of asphaltene is modelled using a multi-phase flash calculation in which the fluid phases are defined with an EOS and the fugacities of components in the solid phase are forecasted using the solid model which described below. The solid phase can include of one or more components. The precipitated phase is deputed as ab ideal mixture of solid components. The fugacity of a precipitating component in the solid phase is calculated by the following relationship [14, 15]:

$$\ln f_s = \ln f_s^* + \frac{v_s(p - p^*)}{RT} \qquad (3)$$

where f_s^* and f_s are respectively the fugacities of pure solid asphaltenes at pressure p^* and p, v_s is the molar volume pf pure solid asphaltenes, R is the universal gas constant and T is the temperature.

Characterization of asphaltene component in the asphalt phase and in solution is the key step in modelling asphaltene precipitation. In this work, after splitting and regrouping the C_{12+}, the new heaviest component (C_{36+}) is divided into two groups: a precipitating component (C_{36B+}) and a non-precipitating component (C_{36A+}). The mole fraction of C_{36A+} and C_{36B+} is computed as following:

$$z_{C_{36B+}} = \frac{w_{C_{36B+}} \times MW_{oil}}{MW_{C_{36B+}}} \tag{4}$$

$$z_{C_{36A+}} = z_{C_{36+}} - z_{C_{36B+}} \tag{5}$$

Table 3 shows the reservoir oil composition after splitting, regrouping and dividing the new heavy component into two groups. These two groups have the same acentric factors and critical properties while their interaction coefficients with the light components are different. The non-precipitating component has the lower interaction coefficient with light components. Larger interaction coefficients exhibit larger incompatibility between the components which in turn favor the formation of the asphalt phase.

3. Results and Analysis

This section shows the results of asphaltene stability study and asphaltene precipitation modeling. First results of asphaltene stability methods for the sample of studied reservoir is discussed, then, results of the PVT simulation (CCE and DL tests) and asphaltene modelling are reviewed.

3.1. Asphaltene Stability

The results of methods for investigating the asphaltene stability indicate that the asphaltene can be formed in this studied reservoir as a results of pressure and temperature changes. If calculated index is greater than 0.9, 0.95 and 0.35 in CII, CSI and SI methods respectively the asphaltene content in the crude oil is unstable. In the studied sample these index are about 2.24, 2.44 and 4 for CII, CSI and SI respectively. The ratio of saturates to aromatics and ratio of asphaltenes to resins for the studied sample is in the unstable region of Stankiewicz plot. For SCP method, the calculated ratios for all plots are in the unstable zone. Figure 3 shows the points of studied sample on stability cross plots. Table 6 indicates the value of calculated ratios for SCP method. Table 7 shows the asphaltene stability results based on the SARA analysis of the reservoir fluid.

Table 6. Values for calculated ratios of studied sample

	y value	x value	Status
SCP1	0.11169	42.5714	Unstable region
SCP2	0.11169	0.25	Unstable region
SCP3	2.23826	0.25	Unstable region
SCP4	0.11169	1.25097	Unstable region

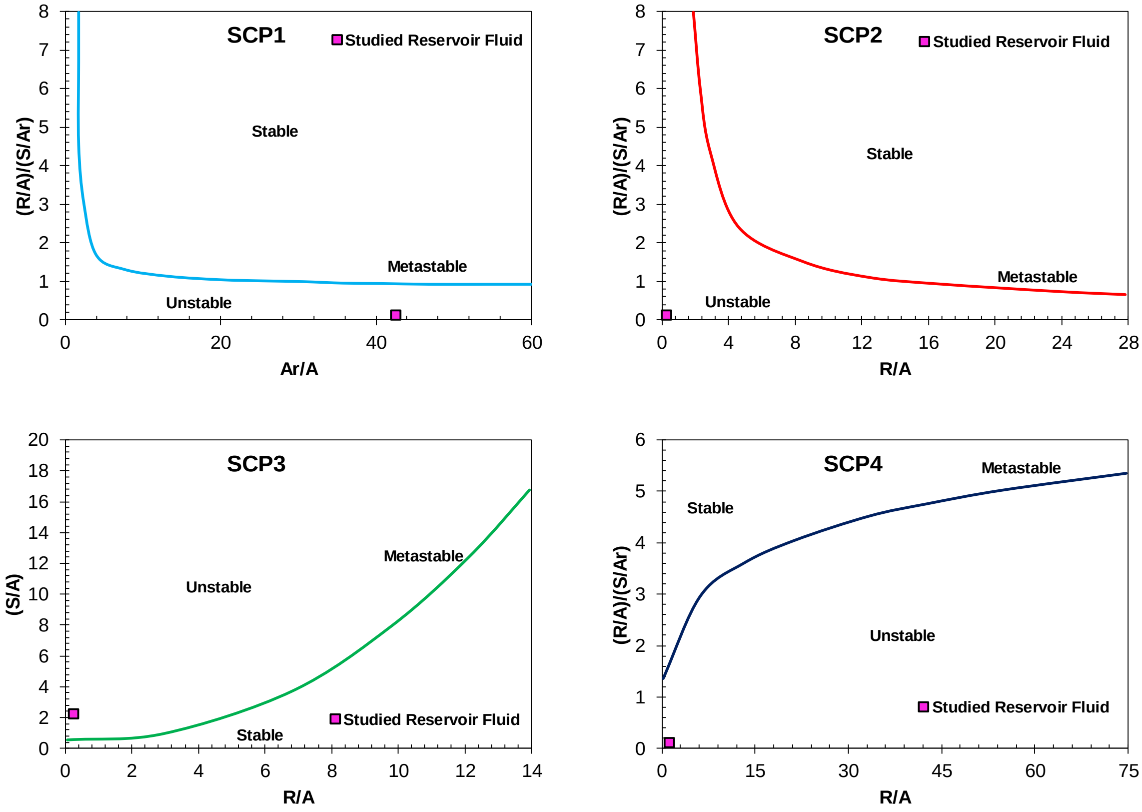


Figure 3. Points of studied sample on stability cross plots

Table 7. Results of asphaltene instability methods

Method	Value for the Studied Sample	Range of Instability	Status
CII	2.2786	CII>0.9	Unstable
CSI	2.4424	CSI>0.95	Unstable
SI	4	SI>0.35	Unstable
Stankiewicz plot	-	Plot Region	Unstable
SCP	-	Plot Region	Unstable

3.2. PVT and Asphaltene Modeling

This modeling was conducted based on the sample of reservoir fluid with the PVT simulator. Figures 4 and 5 show the results of PVT modeling after tuning P-R equation of state.

It is observed that the tunned model can accurately predict the experimental data (reservoir fluid behavior). Figure 6 shows the precipitated asphaltenes formation behavior as a function of pressure for 6 different temperature including the reservoir temperature (T=174 °F).

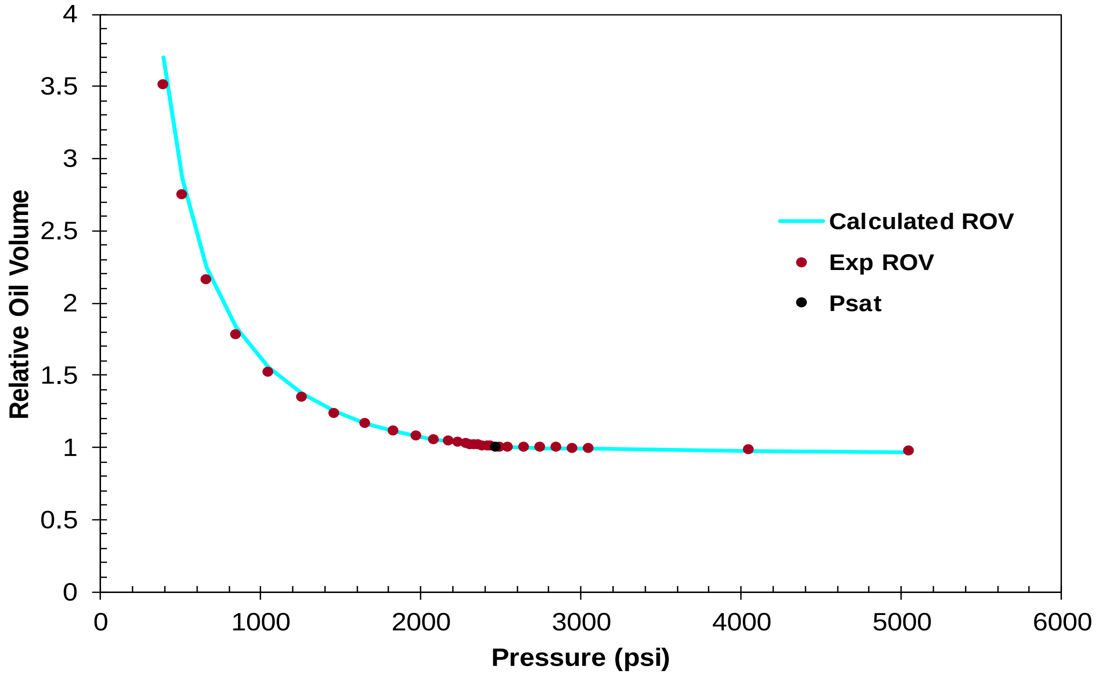
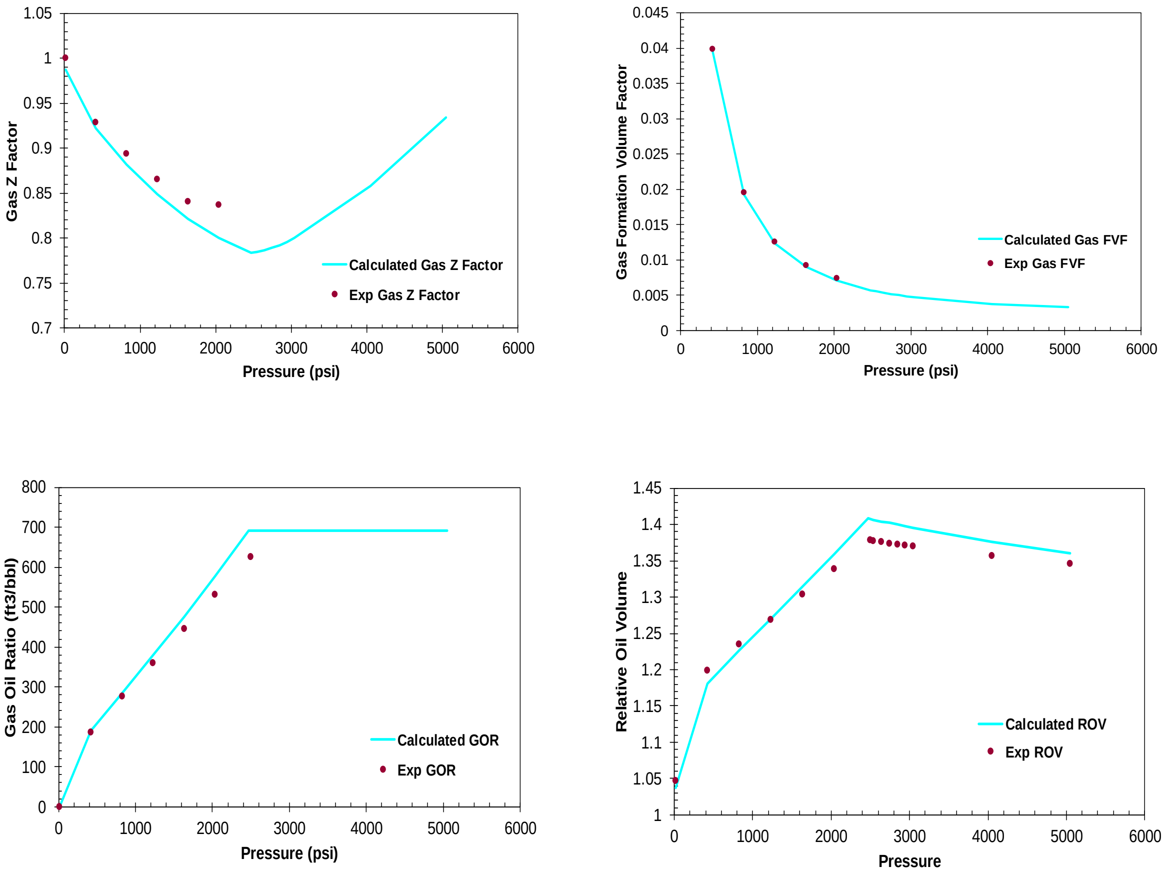


Figure 4. Relative oil valume calculated by model (CCE test)



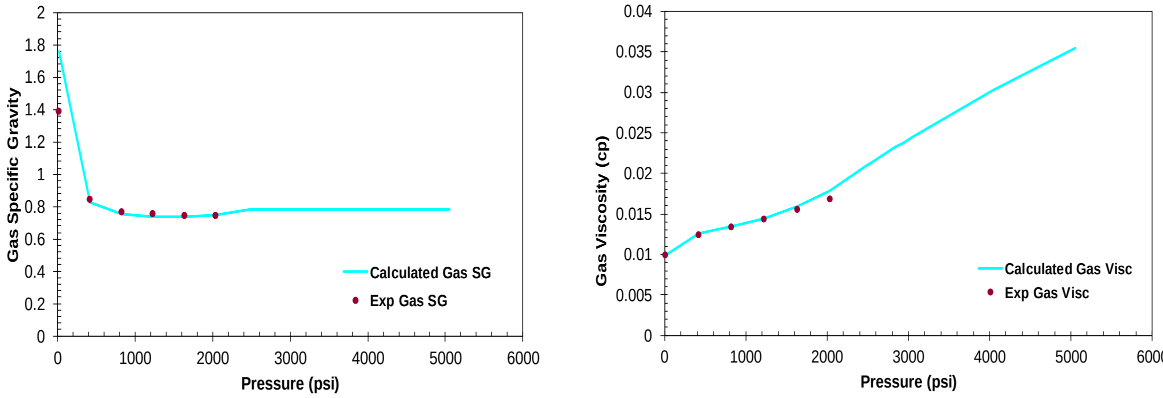


Figure 5- Properties calculated by model and the experimental values in differential liberation test

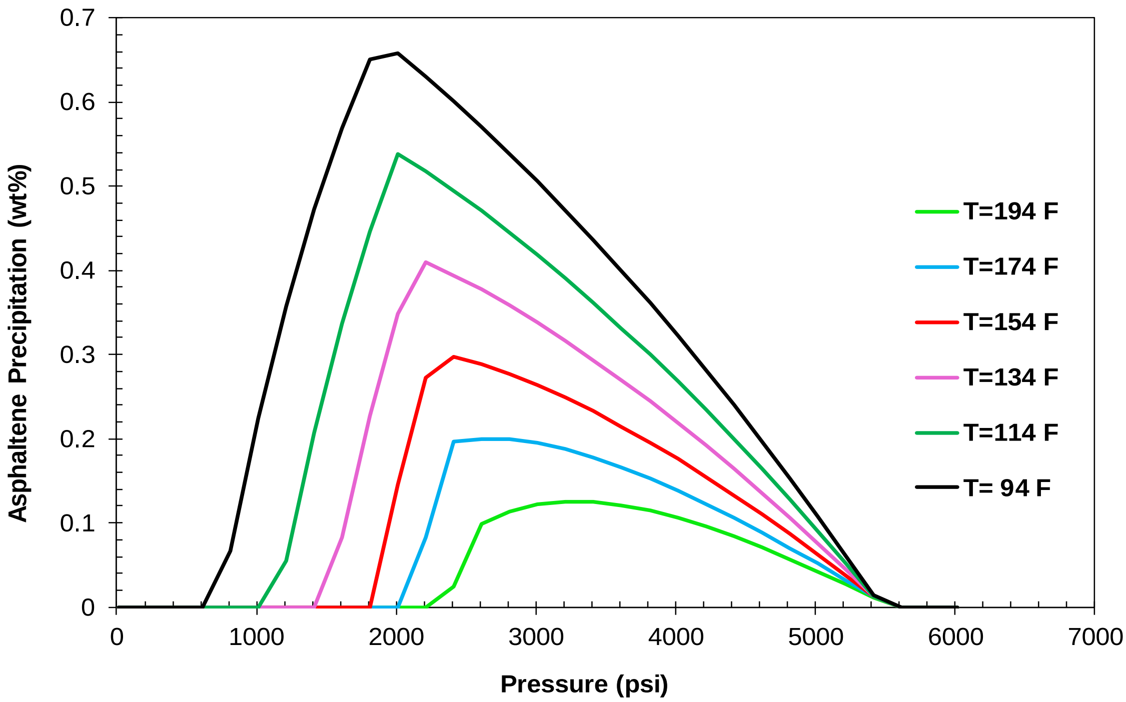


Figure 6. Asphaltene precipitation as a function of pressure for 6 different temperature

Figure 6 indicates that the maximum amount of asphaltene precipitation in reservoir temperature occurs near the saturation pressure. In addition, the pressure range and maximum amount of asphaltene precipitation is increased by decreasing in temperature. This decrease in temperature occurs along the production wells and transmission pipelines therefore that may lead to asphaletene issues in the facility during production from this reservoir.

4. Conclusion

In this study, a model was provided for predicting the phase behavior of an Iranian light oil reservoir. The studied reservoir has high potential of asphaltene precipitation due to its high asphaltene contents and low resin contents. A model was constructed for estimating the asphaltene precipitation of studied reservoir sample as a function of pressure for six different temperatures. Maximum amount of asphaltene precipitation in the reservoir temperature occurs near the bubble point pressure. The pressure range and maximum amount of asphaltene precipitation is increased by decreasing in temperature. Due to decreasing temperature along the wellbore and transmission pipelines, the risk of asphaltene precipitation in these places is increased.

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